Burial History and Hydrocarbon Generation Modeling of the Jurassic-Cretaceous Formations in the Alamein-Shushan Basins, Northern Western Desert of Egypt*

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Abstract

Maturity and petroleum generation modeling of the Jurassic-Cretaceous succession in the Alamein-Shushan basins shows that the dark shale of Khatatba Formation (Middle Jurassic) and the shale of Alam El-Bueib Formation (L. Cretaceous) are the most potential source rocks for oil and gas generation. Detailed biological marker and stable carbon analyses of crude oils representing Alamein, Yidma, North Ras Qattara and Shushan fields revealed two oil families of different geochemical characteristics. Family-I representing crude oil produced from Bahariya Formation (Upper Cretaceous) and Family-II is the crude oil produced from of the Lower Cretaceous formations (Aptian Dolomite, Razzak Sand and Alam El-Bueib) strength the idea of presence of two different source rock intervals for oil generation and entrapments with two levels of thermal maturations. Two different marine shale source rocks were considered in the 2-D modeling of source rock maturation and hydrocarbon generation and each source rock was assigned specific generation potential. Organic rich source rock with excellent potential to generate oil is present in the Middle Jurassic Khatatba Formation entered the overmature to late mature stage of oil and gas generation window at vitrinite reflectance between 1.0 and 1.3 Ro% during the Late Cretaceous. Meanwhile, a good to fair source rock of Alam El-Bueib Formation located within the early to mid mature stage of oil generation window at vitrinite reflectance 0.6 to 1.0 Ro% during the Late Eocene. These source rocks could have charged stratigraphic as well as structural traps that play an important role during the hydrocarbon accumulation. The biomarker variability between the two oil families presumably reinforced the hypothesis that the presence of two independent petroleum systems for oil generation, maturation and entrapment in the Alamein-Shushan basins.

Source Rock Evaluation

A potential source rock has the capability of generation and expulsion thermally mature oil and gas accumulations (Peters and Cassa, 1994). Source rock evaluation includes quantity and quality of organic matter in addition to thermal maturity or burial heating of organic matter buried in sedimentary succession (Waples, 1994). The source rock potential and the hydrocarbon generation of the northern Western Desert of Egypt were studied by many authors among them, Parker (1982), Shahin and Shehab (1988), Taher et al., (1988), Zein El-Din et al., (1990), Abdel-Gawad et al., (1996), Abdou (1998), McCain (1998), Abdel-Aziz and Hassan (1998), Khaled (1999), Ghanem et al., (1999), Sharaf et al., (1999), Wever (2000), Waly et al., (2001), Al-Sharhan and Abdel-Gawad (2002), Shahin and El-Lebbudy (2002), Metwally and Pigott (2002), El-Gayar et al., (2002), El-Nadi et al., (2003) Harb et al., (2003), Younes (2002, 2005 and 2011) and Moretti et al., (2010).

Accordingly, these studies concluded that the stratigraphic section of the northern Western Desert contains multiple source rocks of different degrees of thermal maturation. The dark shale of the Khatatba Formation is considered a mature source rock with an excellent capability for both oil and gas generation. Shale rocks of Alam El-Bueib and Abu Roash-G formations considered a marginally to good mature source rock for oil generation during the Late Cretaceous.

Source rock evaluation were applied on Thirty two core shale rock samples representing the lithostratigraphic succession of Khatatba, Alam El-Bueib and Abu Roash-G formations of the well Shushan-1X and Alamein-1X including total organic carbon (wt.%), pyrolysis parameters (S1 and S2 values) and vitrinite reflectance measurements (Ro%) to evaluate their organic richness, kerogen types, and the degree of thermal maturity in Alamein and Shushan basins.

Quantity of Organic Matter

The available Rock-Eval pyrolysis data of the studied shale rock intervals from the well Shushan-1X and graphically represented in Figure 1. The results show that organic-rich intervals are present at the stratigraphic intervals starting with the oldest.

Khatatba Formation

Khatatba Formation consists of dark shale and contains Total Organic Carbon (TOC) ranges between 3.60 and 4.20 wt.% in Shushan 1-X and between 3.80 and 4.32 wt.% in Alamein 1-X indicating an excellent source rock (Peters and Cassa, 1994). The pyrolysis yield S1+S2 varies between 8.00 and 10.65 kg HC/ton rock in Shushan 1-X and 5.44 and 6.25 kg HC/ton rock in Alamein 1-X. Meanwhile, the mean productivity index (S1/S1+S2) of 1.5, therefore the shale rocks of the Khatatba Formation has an excellent potential source rock for oil and gas generation in the northern Western Desert of Egypt.

Alam El-Bueib Member

The shale section of Alam El-Bueib Member contains TOC varies from 1.85 to 2.40 wt.% in Shushan 1-X indicating a good source rock. The pyrolysis yield S1+S2 ranges between 3.60 and 4.50 kg HC/ton rock and the productivity index (S1/S1+S2) of these rocks are generally less than unity, therefore the shale rocks of the Alam El-Bueib Member has a good source rock generating potential.

Abu Roash-G Member

The organic richness of Abu Roash-G Member varies from 1.10 to 1.50 TOC (wt.%) in Shushan-1X and 0.40 to 1.1 in Alamein-1X reflect a medium to good source rock. The pyrolysis yield S1+S2 ranges between 0.85 and 1.10 kg HC/ton rock and 1.10 to 2.45 kg HC/ton rock in Alamein-1X. The productivity index (S1/S1+S2) of these rocks are generally less than unity in the both wells. Consequently, the shale rocks of Abu Roash-G Member indicating fair source rock generating potential.

Type of Organic Matters (Kerogen Types)

Kerogen types are distinguished using the Hydrogen Index (HI) versus Oxygen Index (OI) on Van Krevelen Diagram originally developed to characterize kerogen types (Van Krevelen, 1961 and modified by Tissot et al., (1974). The figure shows that Khatatba, Alam El-Bueib and Abu Roash shales contain a mixed kerogen types II-III. This kerogen type of mixed vitrinite-inertinite derived from land plants and preserved remains of algae (Peters et al., 1994). Mixed kerogen type characterizes mixed environment containing admixture of continental and marginal marine organic matter have the ability to generate oil and gas accumulations (Hunt, 1996).

Thermal Maturity of Organic Matters

The thermal maturation of organic material is a process controlled by both temperature and time (Waples, 1994). The vitrinite reflectance is used to predict the thermal maturation and hydrocarbon generation.

The data of vitrinite reflectance measurements (Ro%) for the studied wells Shushan-1X and Alamein-1X were plotted against depth (Figure 2) to indicate that the phases of hydrocarbon generation and expulsion. The relationship between Hydrogen Index (HI) and Maximum Temperature (Tmax) to the studied shale source rocks of the Khatatba, Alam El-Bueib and Abu Roash-G succession indicate that the shale source rocks of Khatatba Formation are located within the oil and gas generation window and considered an excellent source rock potential. Meanwhile, the shale rocks of Alam El-Bueib and Abu Roash-G members are considered a good to fair source rock for oil generation having a less degree of thermal maturation in comparable with the shale source rock of Khatatba Formation.

Based on the maturity profile in the burial history model of the well Shushan-1X and Alamein-1X (Figure 2). The burial history model of the different hydrocarbon bearing rock units indicate that the shale source rock of Khatatba Formation entered the late mature stage of hydrocarbon generation window between vitrinite reflectance measurements between 1.0-1.3 Ro% during the Late Cretaceous. The shale source rock of Alam El-Bueib Member entered the mid mature stage of oil generation window between vitrinite reflectance measurements between 0.7-1.0 Ro% during the Late Cretaceous while shale source rock of Abu Roash-G Member entered the early mature stage of oil generation at vitrinite reflectance values between 0.5-0.7 Ro% at time varying from Late Cretaceous to Late Eocene.

Crude Oil Characteristics

Gross and C7 Light Hydrocarbon Geochemistry

Taher et al., (1988) and Halim et al., (1996) used the biomarker properties and stable carbon isotope composition of crude oils from different discoveries from the northern Western Desert of Egypt to assess the genetic relationship between hydrocarbon generation and their source rock depositional conditions. Eighteen crude oil samples were conducted from the fields of Alamein and Shushan. Thirteen crude oil samples were collected from Alamein fields namely, Alamein, North Ras Qattara and Zain in addition to five crude oil samples from Shushan fields namely, Hayat, Safir, Tut, Yasser and Salam.

These crude oils have a wide range of API gravities between 22.05° and 48° and correspond to a low variation of sulfur contents ranges between 0.14 to 2.67%. Liquid chromatographic data indicates a predominant composition of paraffinic composition with little branched or cyclic materials waxy n-alkanes (C_{25}-C_{31}).

Source-Dependent Biomarker Distributions

Biomarkers are compounds that characterize certain biotic sources and retain their source information after burial in sediments (Meyers, 2003). Biomarker distributions are used for oil-oil and oil-source rock correlations to assess the source of organofacies, kerogen types and the degree of thermal maturity (Philp and Gilbert, 1986; Waples and Machihara, 1991; Peters and Moldowan, 1993; Peters and Fowler, 2002). Gas chromatographic analyses data indicate the predominance of pristane over phytane (Pr/Ph) ratios between 1.51 and 4.50, while Carbon Preference Index (CPI) are generally >1 that are typical of terrestrially sourced oils (Moldowan et al., 1985). A plot of Pr/n-C_{17} versus Ph/n-C_{18} (Figure 3) indicates that the studied crude oils were derived from shale source environment (Shanmugam, 1985).

The ratio of Ts/Tm is considered as a facies and depositional environmental parameter of the relevant source rocks (Bakr and Wilkes, 2002). It is also considered a maturation parameter due to the greater thermal stability of Ts (18α(H)-22,29,30-trisnorneohopane) than its counterpart Tm (17α(H)-22,29,30-trisnorhopane) (Seifert and Moldowan, 1978; Cornford et al., 1988; Isaksen, 2004). The calculated ratios of Ts/Tm for the crude oils are generally less than unity and consistent with the C35/C34 homohopanes and the oleanane index that ranges between one and four while the gammacerane index ranges between three and seven. The moretane index is concentrated between 10 and 16 indicating that these crude oils have been generated from reducing and low saline shale source rock of mixed kerogen types II-III of Mesozoic age (Younes, 2002 and Moretti et al., 2010). The sterane distributions of C_{27}, C_{28} and C_{29} isomers for the studied crude oils recovered from Alamein-Shushan fields are shown in Figure 4. Increasing the relative concentration of C_{29} sterane distribution of Bahariya crudes enable from good separation of the terrestrial shale source rocks from the lacustrine shale source of the crude oils produced from the different pay zones of Alamein-Shushan fields (Moldowan et al., 1985; Peters and Moldowan, 1991).

Maturation-Dependent Biomarker Distributions

Biomarker maturity parameters, including the sterane isomerization, C_{29} ααα20S/(S+R), and ratios based on the mono-and triaromatic steroidal hydrocarbon distributions (m/z 253 and 231). These parameters also clearly indicate the maturity levels of the studied crude oils from Alamein-Shushan fields. Increasing source rock maturation from diagenesis to catagenesis is accompanied by an increase in the degree of aromaticity that converts monoaromatic steroids (MAS) to triaromatic steroids (TAS) lead to an increase thermal maturity through diagenetic/metagenetic processes results in the conversion of monoaromatic steroid to triaromatics (Seifert and Moldowan, 1978). Triaromatic/monoaromatic maturity parameters (TAS/MAS+TAS) for all isomers and C_{27}/C_{28} ratios found to be averaged 0.6 and 0.8 indicating a predominance of triaromatic relative to monoaromatic steroids for the studied crude oils which in turn the higher maturity level source rock in Alamein-Shushan fields.

The relationship plotting between sterane isomerization ratios C_{29}ααα 20S/(S+R) and C_{29}αßß/(αßß+ααα) that according to Seifert and Moldowan (1981), are genetically related to the effect of thermal maturity processes. It shows that there is a direct relationship between C_{29}ααα 20S/(S+R) and C_{29}αßß/(αßß+ααα) increasing with burial depth of the source rocks and the studied crude oils are located within the oil generation window (Matava et al., 2003). The studied crude oils from Alamein-Shushan fields have a maximum value of sterane isomerization ratios; C_{29}ααα 20S/(S+R) and C_{29}αßß/(αßß+ααα) of 0.4 and 0.6 respectively that support the relative higher maturation level of the studied crude oils.

Diasterane/sterane ratios are highly dependent on both the nature of the source rock and level of thermal maturity. This ratio is commonly used to distinguish carbonate from clay rich source rocks and can be used to differentiate immature from the highly mature oils (Seifert and Moldowan, 1978). The studied crude oils from Alamein-Shushan fields are slightly depleted in diasteranes <1 probably reflecting the shale source input (Kennicutt et al., 1992).

Aromatic sulfur compounds such as dibenzothiophene (DBT) and methyldibenzothiophenes (MDBT) can be used as maturity indicators of source rock and petroleum (Chakhmakhchev et al., 1997; Radke et al., 1997). The plotting of the ratio of DBT/Phenanthrene versus Pristane/Phytane ratios on the diagram of Hughes, et al., (1995) enabled a complete separation of two different sources of different maturity level. The Bahariya crudes may have been generated from fluvio-deltaic shale source rock, while the other crude oils from different pay zones may have been generated from marine and lacustrine shale source rocks of marginally mature basin in the Alamein-Shushan fields (Figure 5).

Stable Carbon Isotopic Composition

The stable carbon isotopic composition of organic matter is an important tool in differentiating algal from land plant source materials and marine from continental depositional environments (Meyers, 2003). Rohrback (1982) and Zein El-Din and Shaltout (1987) found that the crude oils produced from Bahariya Formation were relatively light with $\delta^{13}C$ values for the saturate fractions of -26‰, while to the aromatic fraction ranging between -25 to 24.5‰. These values are isotopically identical and appear to be generated from a source rock containing marine organic matters as previously concluded from the relation achieved between aromatic sulfur compound and pristine/phytane ratios. Plotting of the $\delta^{13}C$ composition of the saturate and aromatic hydrocarbon fractions of the crude oils from Alamein-Shushan oilfields (Figure 6) in addition to the calculated canonical variable relationship: $CV= -2.53\delta^{13}C_{sat}+ 2.22\delta^{13}C_{arom}– 11.65$ postulated by (Sofer, 1984).

Family-I represents the Bahariya oil yields canonical variable values are generally < 0.47 indicating non-waxy oils and may be sourced from shale source rock of Alam Bueib Member (L. Cretaceous), while the crude oils produced from the other pay zones (Family-II) yields canonical variable parameter value >0.47 indicating terrestrial source most probably the Jurassic dark shale of Khatatba Formation .

Conclusions

Detailed biological markers and stable carbon isotope composition of crude oils representing Alamein and Shushan fields revealed two oil families of different geochemical characteristics. Family-I representing crude oil produced from Bahariya Formation (Upper Cretaceous) and Family-II is the crude oil produced from of the Lower Cretaceous formations (Aptian Dolomite, Razzak Sand and

Alam El-Bueib members) strength the idea of presence of two different source rock intervals for oil generation and entrapments with two levels of thermal maturations. Two different marine shale source rocks were considered in the 2-D modeling of source rock maturation and hydrocarbon generation and each source rock was assigned a specific generation potential. Organic rich source rock with excellent potential to generate oil and gas is present in the Middle Jurassic Khatatba Formation that entered the late mature stage of oil and gas generation window at vitrinite reflectance between 1.0 and 1.3 Ro% during the Late Cretaceous. Meanwhile, a good to fair source rock of Alam El-Bueib Member is located within the early to mid mature stage of oil generation window at vitrinite reflectance 0.6 to 1.0 Ro% during the Late Eocene.

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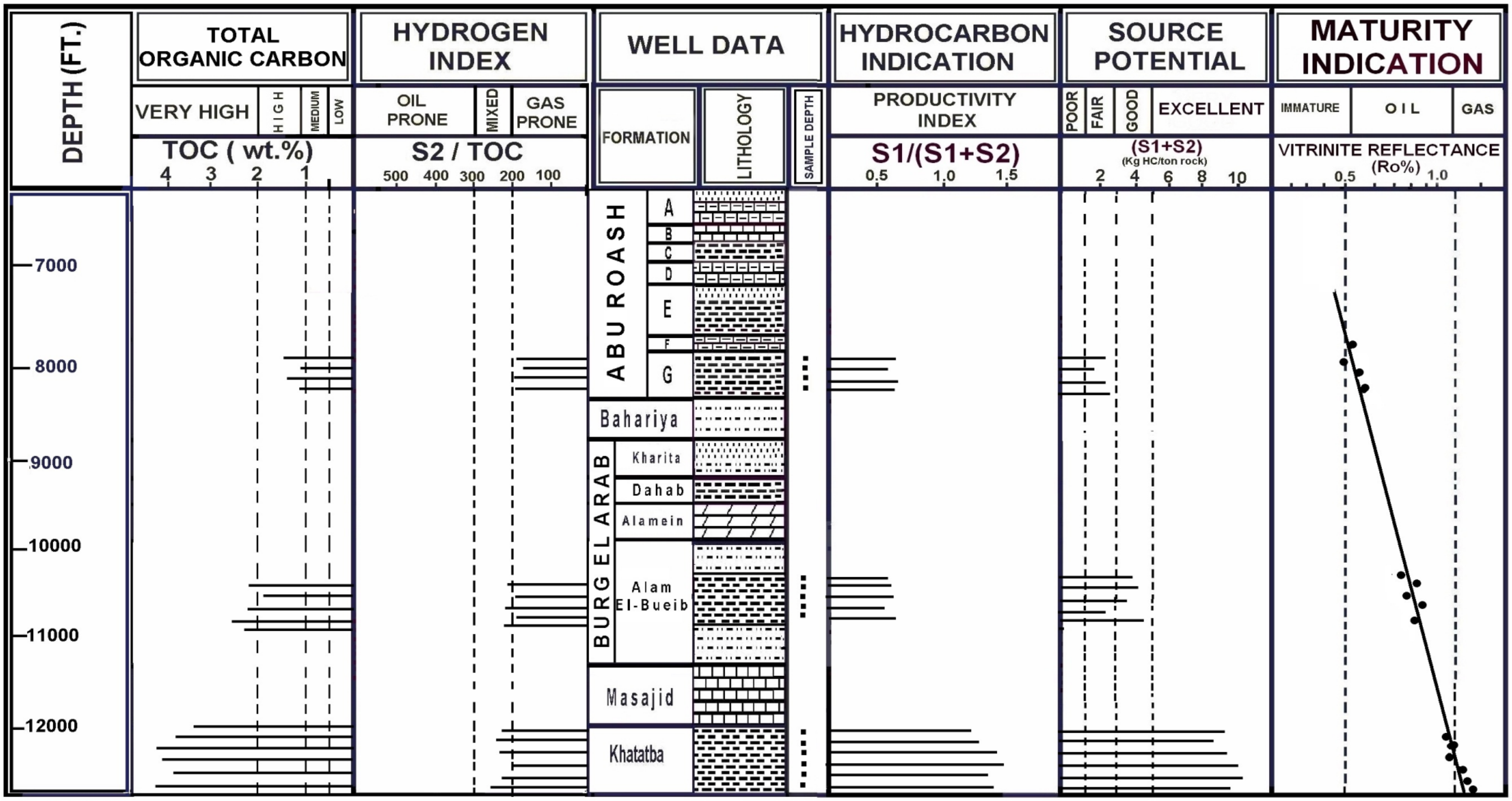

Figure 1. Idealized geochemical log to the well Shushan-1X, showing Rock-Eval pyrolysis data, total organic carbon and vitrinite reflectance measurements.

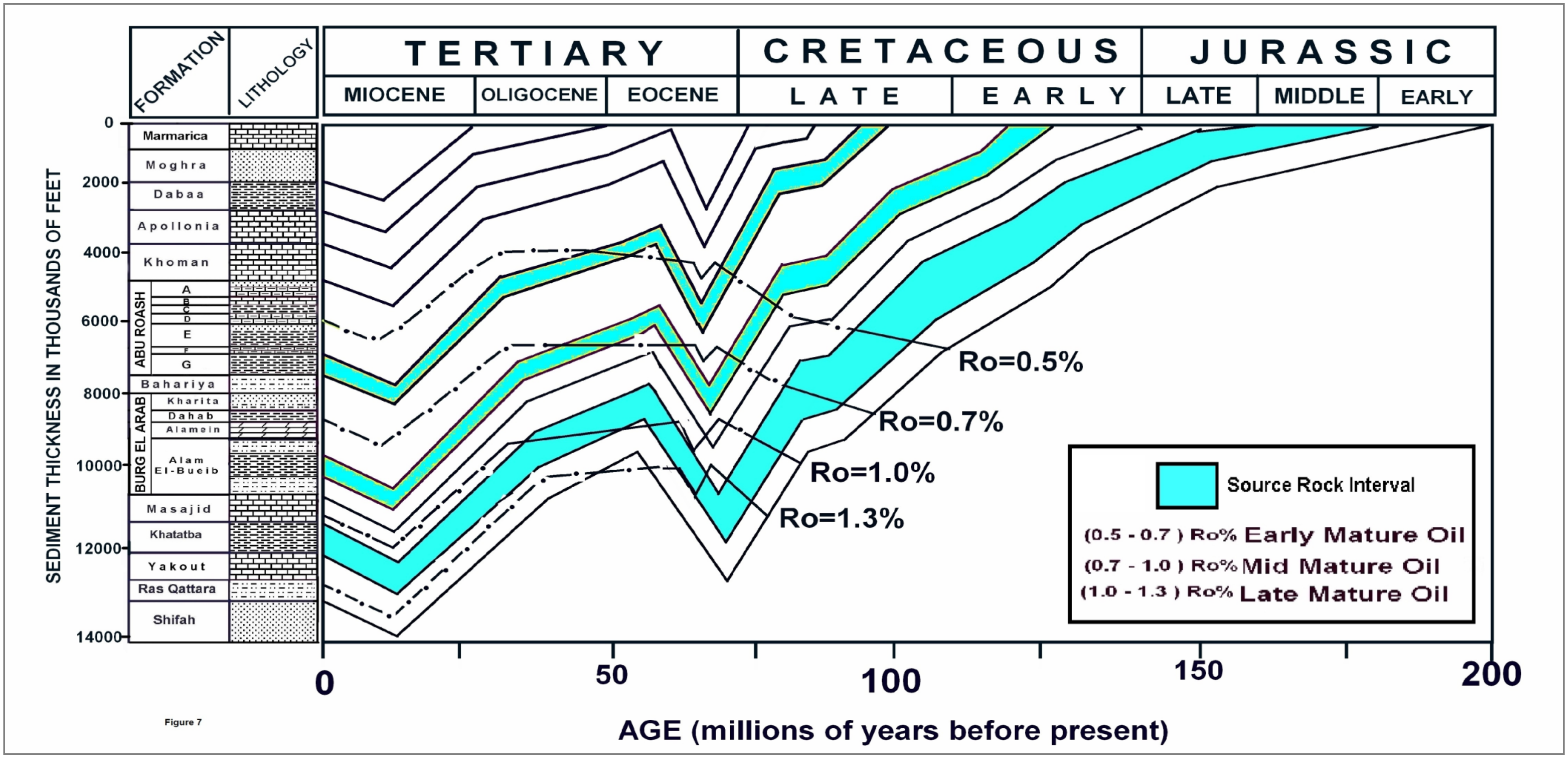

Figure 2. Burial history model of the well Shushan-1X and stages of hydrocarbon generation windows.

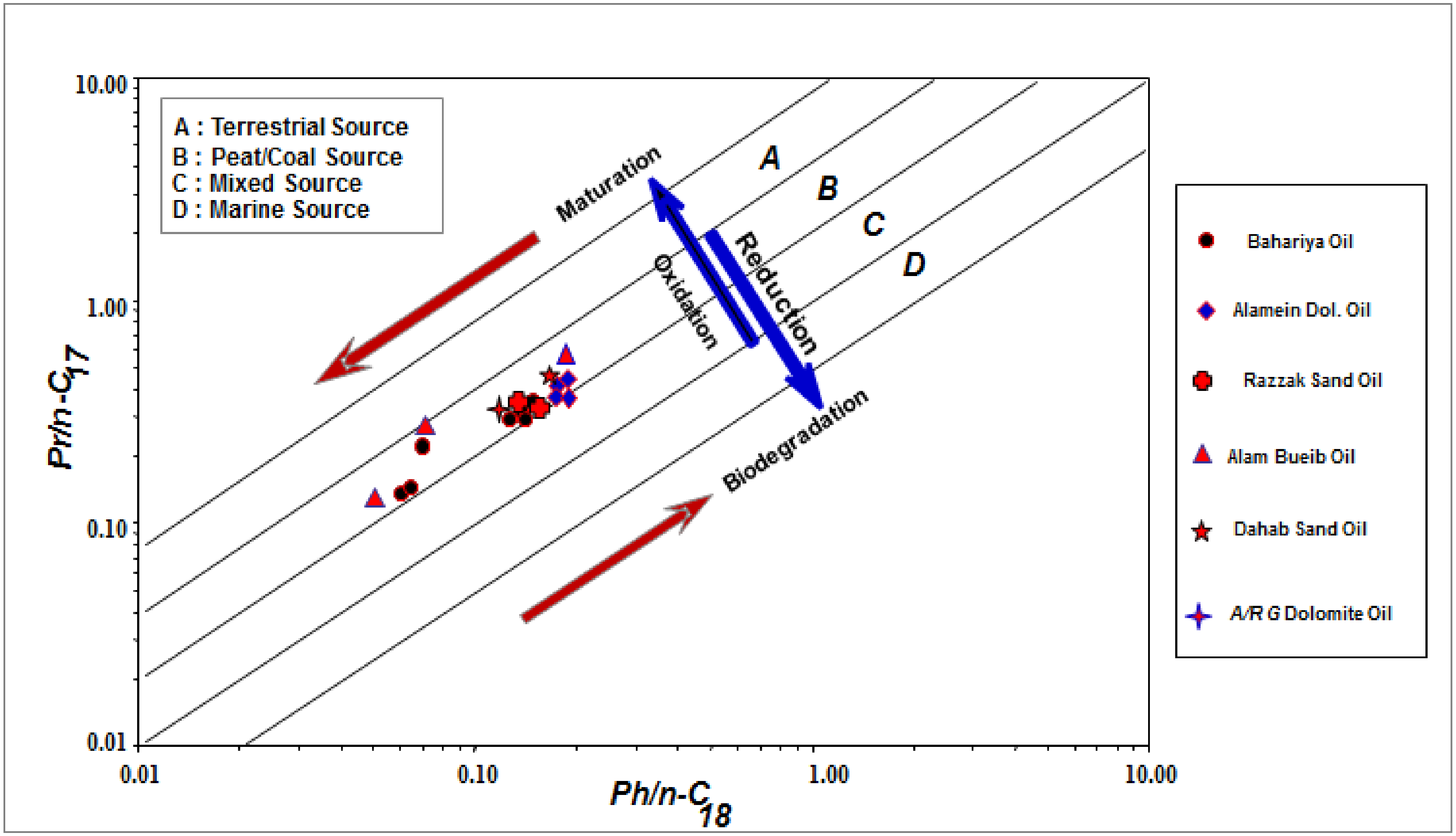

Figure 3. Plot of Pr/n-C_{17} versus Ph/n-C_{18} and the location of the crude oils of Alamein and Shushan fields (Shanmugam, 1985).

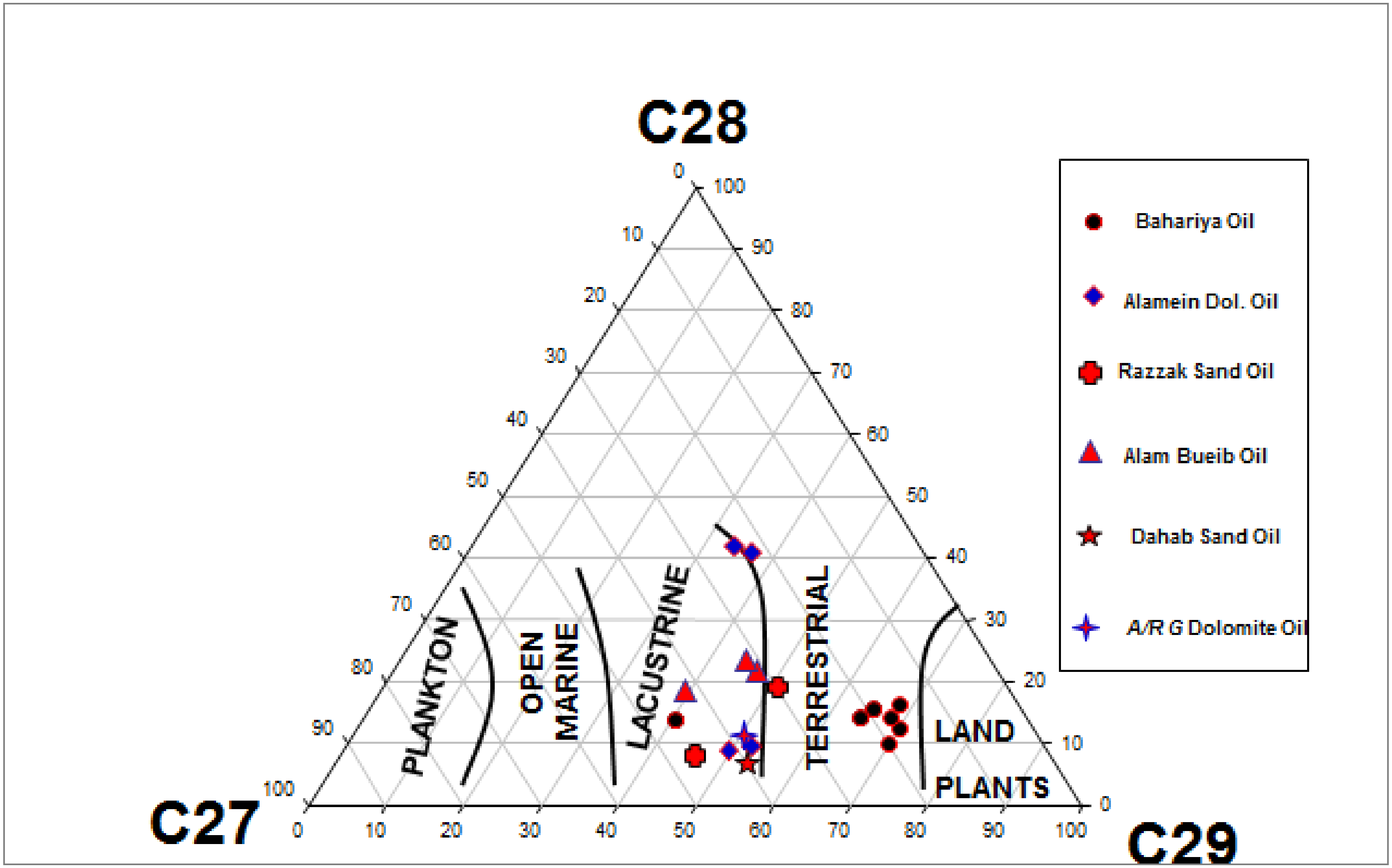

Figure 4. Ternary diagram representing the plot of C_{27}, C_{28} and C_{29} monoaromatic steroids of Alamein and Shushan crude oils (Peters and Moldowan, 1993).

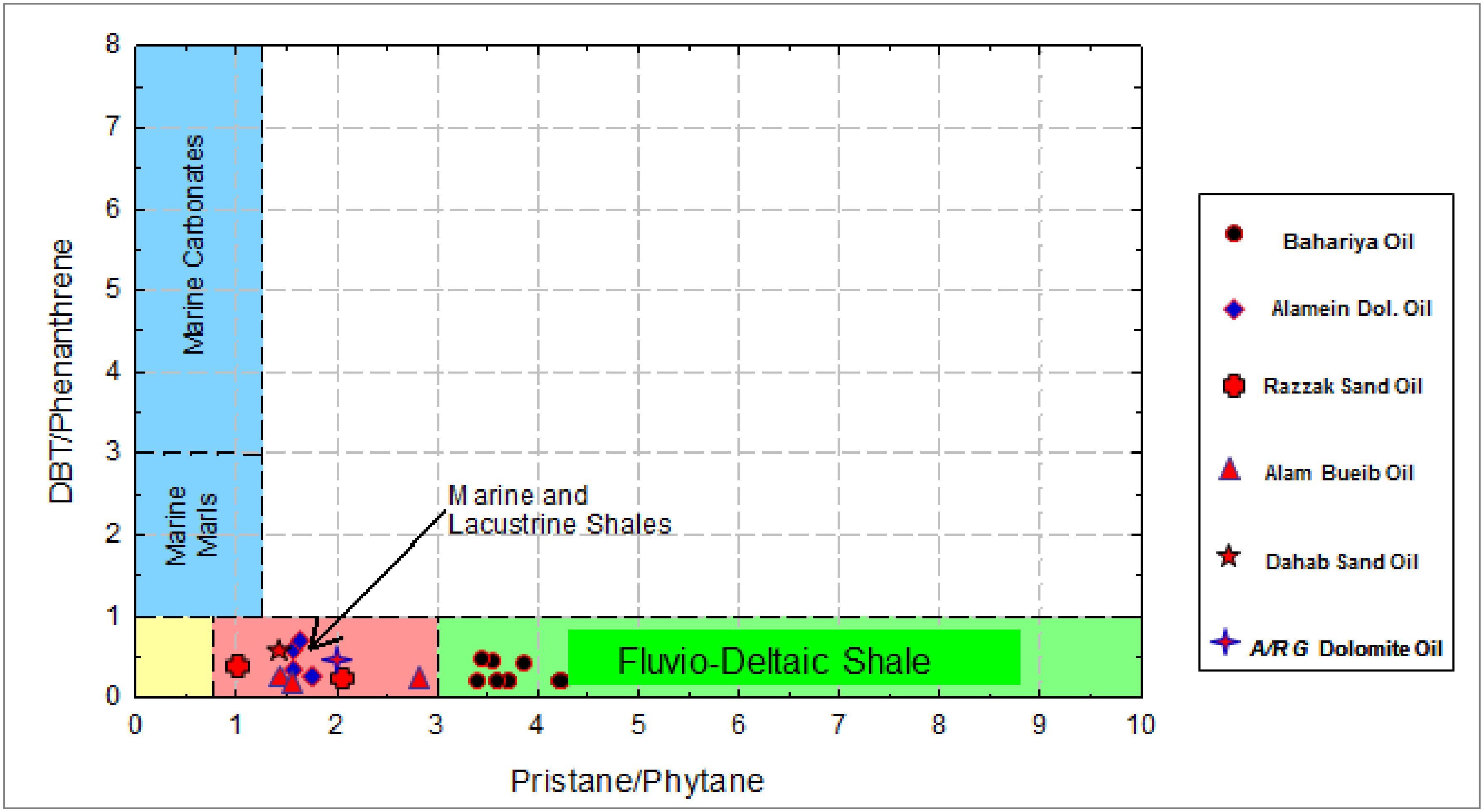

Figure 5. Crossplot of Pristane/Phytane versus DBT/Phenanthrene for crude oils from Alamein and Shushan fields (Hughes, et al, 1995).

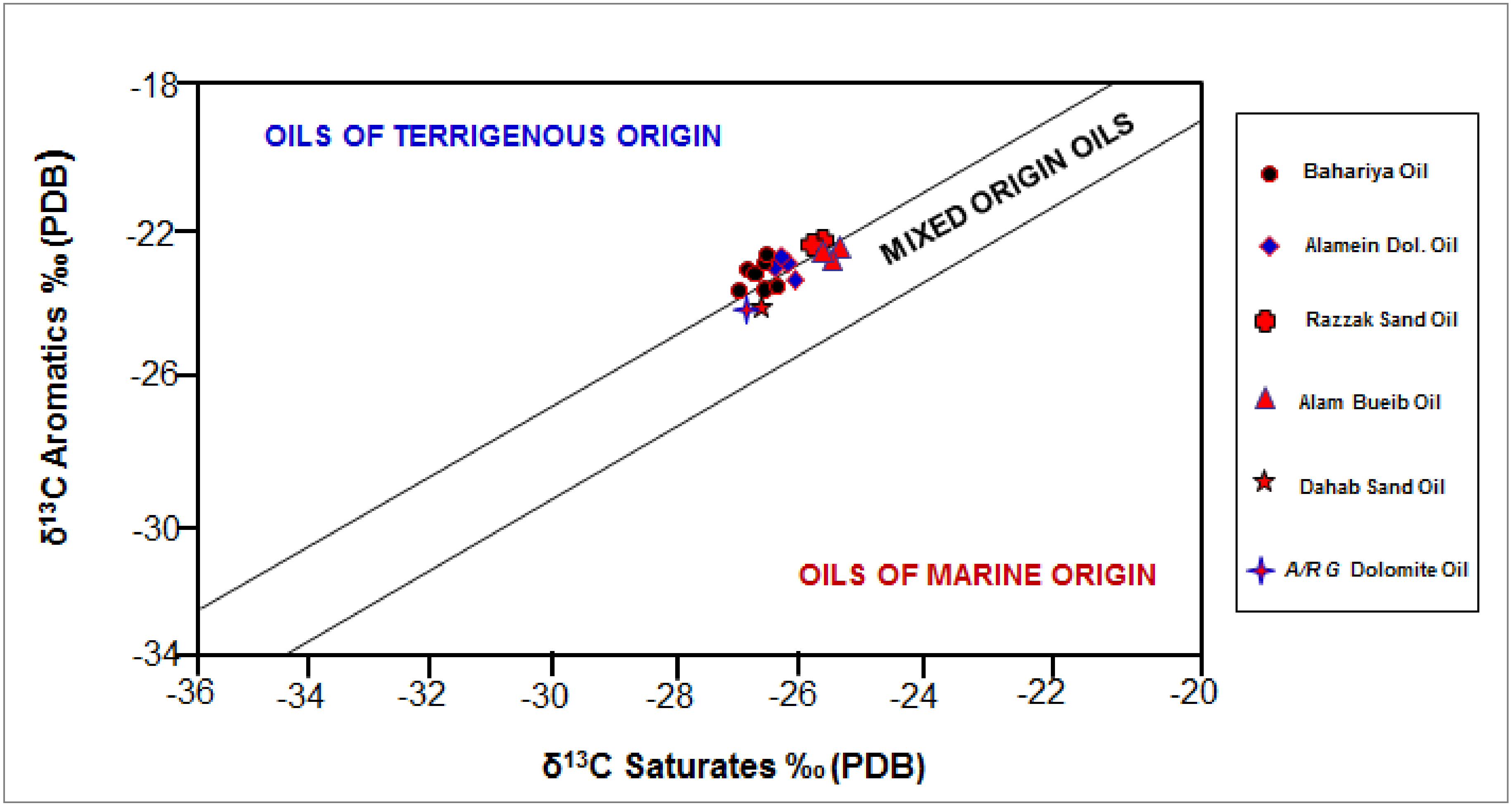

Figure 6. Stable Carbon isotope composition of aromatics vs. saturates for crude oils from Alamein and Shushan fields (after Sofer, 1984).